TECHNICAL REVIEW AND EVALUATION OF APPLICATION FOR AIR QUALITY PERMIT NO. 1000940

I. INTRODUCTION

This Class I (Title V) Permit is for the operation of the Griffith Energy Project (Griffith Energy), located off Interstate-40 south of Kingman, Arizona. The Project is owned by Griffith Energy LLC. This is a new project that would generate electricity produced by natural gas combustion for wholesale in the surrounding area.

A. Company Information

Facility Name: Griffith Energy LLC
Mailing Address: 11350 Random Hills Rd., Suite 400, Fairfax, Virginia 22030
Facility Address: SW 1/4 of Section 6, Northwest of Griffith Interchange, Highway 40, Mohave County, Arizona

B. Attainment Classification

The source is in an attainment area for all criteria pollutants: Total Suspended Particulate (TSP), PM-10, NO_2, SO_2, CO, Pb, and ozone.

II. PROCESS DESCRIPTION

The Griffith Energy Project is an electric generation plant with a nominal base load of 520 MW and a peaking capacity of 650 MW. The primary processes at this facility consist of the following equipment:

- 2 Westinghouse 501F combustion turbine generator units (CTGs) or equivalent F Class CTGs with dry Low NOx combustors
- 2 heat recovery steam generators (HRSGs) with supplemental duct firing
- 1 steam turbine generator unit
- 2 selective catalytic reduction (SCR) systems for controlling NOx

The support processes at this facility will consist of the following equipment:

- 1 auxiliary boiler
- 1 8-cell cooling tower for the steam turbine condenser and equipment cooling
- 1 6-cell cooling tower for the CTG chiller
- 1 emergency diesel fire pump

- Main transformers
- Other ancillary equipment

A process flow diagram of the Griffith Energy Project is presented in Figure 1. The turbine generators and auxiliary boiler will be powered by natural gas. The purpose of the auxiliary boiler is to maintain steam turbine temperatures during periods of steam turbine shut downs, and to provide heat or steam to other processes when required.

The combustion turbine compresses chilled air which is mixed with natural gas and burned in the dry low NOx combustors. The resulting high temperature gases pass through the power turbine and exhaust to the Heat Recovery Steam Generators (HRSGs). The power turbine drives both the compressor and the generator. The generators on each CTG are capable of producing 183 MW. The combustion gases are treated with an SCR system to further control NOx emissions before being exhausted to the atmosphere.

The HRSGs are boilers which generate steam from the heat in the CTG exhaust gases. To increase overall output from the facility, supplemental (duct) firing of natural gas in the HRSGs may be performed to further increase the temperature of the CTG exhaust gases so that additional steam can be produced for the steam turbine generator (STG). The STG is capable of generating 300 MW.

Low pressure, low temperature steam exhausted from the STG is condensed in the main condenser. The condensate is recycled for use in generating more steam. The condenser is cooled by the circulating water system which rejects waste heat to the atmosphere by evaporation in the cooling tower.

The permit emission rates, air quality impact analysis, etc., are based on full load operation year round for the CTG/HRSGs, auxiliary boiler, and cooling towers. The maximum electric power production rates on an annual basis and operating hours of the generating units at Griffith Energy are summarized in Table 1. No alternate operating scenarios are proposed by the applicant.

III. EMISSIONS

The Griffith Energy facility will burn only natural gas, at a maximum rate of approximately 44,000 million standard cubic feet per year (MMscf/year). Maximum heat inputs and fuel consumption for the plant's emission sources are presented in Table 2. Emissions provided by the applicant are for 24-hour per day and 365 days per year of operating time for all equipment, and are presented in Table 8. Griffith Energy has not made a final selection of equipment as of this technical review. Therefore, the applicant has assumed maximum heat input and equipment with the highest level of emission rates anticipated to insure that future compliance will be achieved when final equipment selection is made.

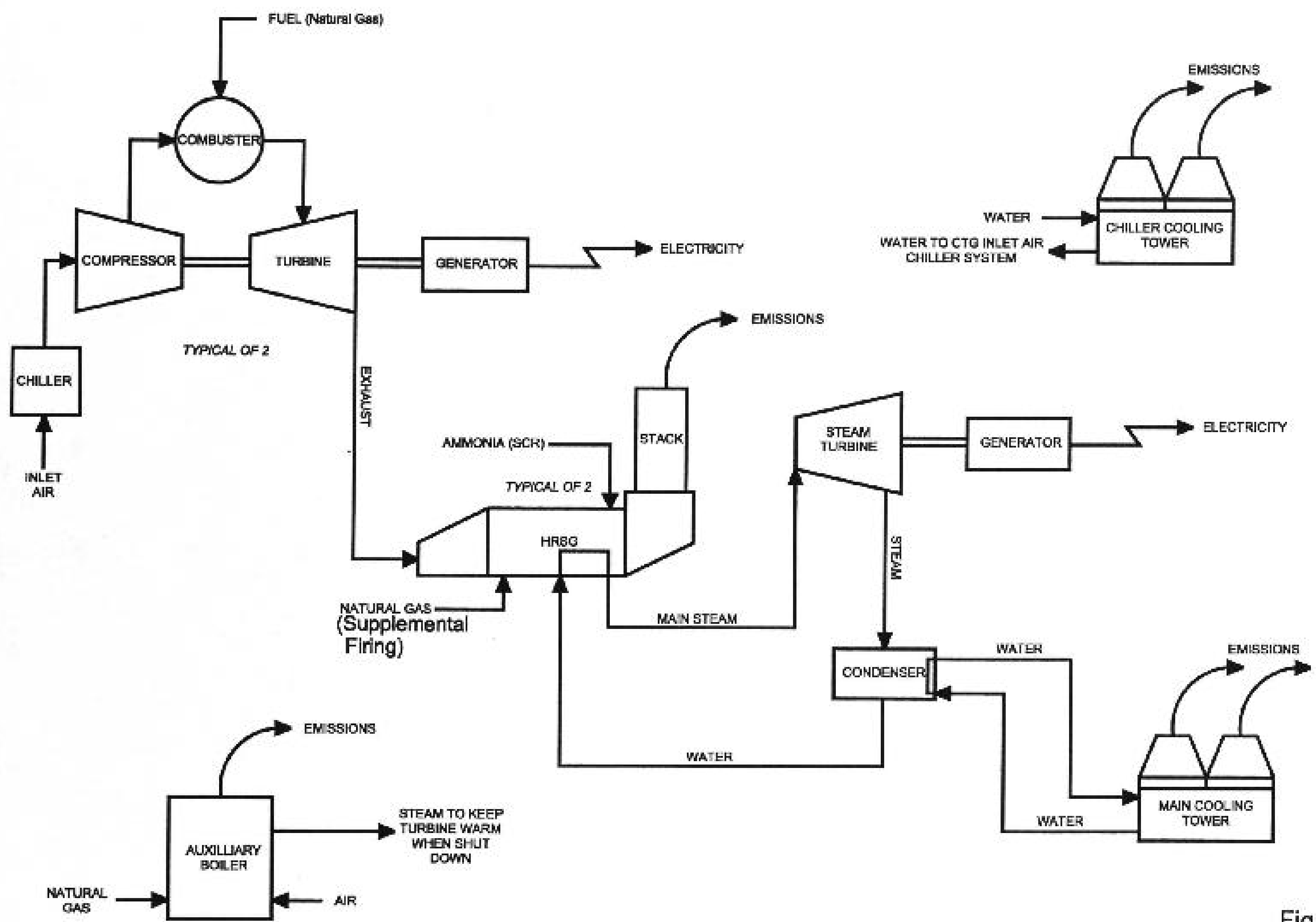

Figure 1
Griffith Energy Project
Process Flow Diagram

Table 1: Maximum Electric Power Production Rates

Emission ID/Unit	Hours/yr	MW	MW-hr/yr
Combustion Turbine Generator Unit 1	8760	183	1,576,800
Combustion Turbine Generator Unit 2	8760	183	1,576,800
Steam Turbine Generator	8760	300	2,540,400
Total			5,694,000

Note: The information in this table was provided by Griffith in their application for a Class I Permit. The process rates and operating hours listed are for informational purposes only. In addition, this information should not be construed as establishing enforceable limitations of any form on Griffith operations.

The small auxiliary boiler will utilize low NOx burners and flue gas recirculation to control NOx emissions. Combustion controls will mitigate emissions of carbon monoxide (CO), particulate matter less than 10 micrometers in aerodynamic diameter (PM-10), and volatile organic compounds (VOCs). To limit emissions of sulfur oxides (SOx), the maximum allowable sulfur content in the natural gas will be 0.75 grains/100 dry standard cubic feet (gr/dscf).

Table 2: Maximum Heat Input and Fuel Consumption

	Heat Input (HHV) in MMBtu/yr	Heat Input (HHV) in MMBtu/hr	Natural Gas Usage* in MMscf/yr	Natural Gas Usage* in MMscf/hr
2 CTGs	3.20E+07	3,658	32,044	3.658
2 HRSGs with Supplemental Duct Firing	1.14E+07	1,300	11,388	1.30
Auxiliary Boiler	3.31E+5	37.8	331.1	0.0378
Total	4.37E+07	4,996	4.37E+04	4.996

*Natural gas heating value assumed to be 1000 Btu/scf.

IV. BEST AVAILABLE CONTROL TECHNOLOGY

As required by PSD regulations, Griffith Energy will be using air pollution control techniques for each pollutant subject to review which have been analyzed and are deemed to be "Best Available Control Technology," or BACT, to control emissions from its emitting sources. All equipment will be fired with natural gas exclusively.

A) CTG/HRSG

The CTG/HRSG units will be equipped with a selective catalytic reduction (SCR) system and low-NO_x combustors to control NOx emissions to 3.0 ppm. Combustion controls will mitigate emissions of CO, PM-10, and VOCs. To limit emissions of SOx (SO_2 and SO_3), the maximum allowable sulfur content in the natural gas will be 0.75 grains/100 dscf.

1) Nitrogen Oxides

The applicant considered a number of measures for the control of NO_x emissions from the proposed project, including both in-combustor NO_x formation control, and post-combustion emission reduction. In-combustor CTG NO_x controls considered included water injection and the use of dry low-NO_x combustors. Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), SCONOx, and XONON were considered as post-combustion NO_x control systems.

Though water injection is an effective means of lower NO_x emissions, it was rejected in favor of dry low-NO_x burners due to water availability problems. Both dry low-NO_x burners and water injection result in higher VOC and CO emissions, but these effects will be minimized by high combustion temperatures, adequate excess air, and good air-to-fuel mixing during combustion.

Among post-combustion control systems, the XONON catalytic system was ruled out because it is an emerging technology and is not expected to be commercially available for CTGs of the size proposed for this project until 2001. SNCR was also rejected as a possible control system because the exhaust temperature at the exit of the CTG is too low to accommodate this technology.

The SCONOx system was eliminated for both technical and economic considerations. The SCONOx system, in its current form, has been operating for approximately two years on a single 30 MW unit, one-sixth of the size of each of the CTGs included in this project. The limited operating time of the SCONOx system raises concerns regarding catalyst life and long-term operational capability. A cost analysis of both the SCONOx system and a combined SCR and oxidation catalyst system, which would achieve reductions similar to the SCONOx system, shows a hundred times greater incremental cost effectiveness in dollars per ton of pollutant controlled for the SCONOx system.

SCR systems were considered which would reduce outlet NO_x emissions to 9.0, 4.5, 4.0, 3.5, 3.0 and 2.5 ppmvd at 15% O_2. The incremental cost effectiveness, in dollars per ton of pollutant controlled, of achieving reductions to 2.5 ppm was shown to be more than two times greater than that of achieving reductions to 4.5 ppm. The applicant proposed that an SCR control system that reduces NO_x to 4.5 ppm, combined with dry low-NO_x burners be used as BACT for NO_x. A comparison of the control systems considered by the applicant are presented and compared with previously permitted control systems taken from the RACT/BACT/LAER Clearinghouse (RBLC) in Table 3.

After considering the available data, and the emission limits for the nearby Calpine Southpoint Project, ADEQ concludes that an SCR control system which reduces NO_x, with or without duct firing, to 3.0 ppmvd at 15% O_2, or 28.6 lb/hr with duct firing and 21.1 lb/hr without duct firing, represents BACT for the CTG/HRSG.

2) Carbon Monoxide

The applicant considered catalytic oxidation and good combustion controls as possible control technologies for CO. Catalytic oxidation, though it can be an effective control on CO emissions, was ruled out due to its negative energy, environmental, and economic impacts.

Energy requirements would be negatively impacted by an increase in back pressure from an oxidation catalyst system, resulting in decreased energy sales. The environmental benefit from use of an oxidation catalyst would be a minor reduction in impact from the estimated maximum air quality impact of 1.0 to 1.4 percent of NAAQS demonstrated by the modeling.

In addition to the negligible environmental benefit, there are also environmental costs associated with the use of oxidation catalysts. Though the spent catalyst is not considered toxic, it does represent additional waste that requires disposal. Also, the effective power reduction that occurs due

Table 3: CTG/HRSG BACT Comparison for NO_x

Facility	Process	Control Technology	Emiss. Limit	Emiss. Limit Unit	Cntrl. Eff.	Tons Controlled	Cost ($)	$/ton Controlled
Griffith	CTG/HRSG	SCONOx	2.5	ppmv	90	968.7	5393000	5567
Griffith	CTG/HRSG	SCR/Oxidation Catalyst	2.5	ppmv	90	968.7	2059000	2126
Griffith	CTG/HRSG	SCR	2.5	ppmv	90	968.7	1534000	1584
Griffith	CTG/HRSG	SCR	3	ppmv	88	947.8	1461000	1541
Griffith	CTG/HRSG	SCR	3.5	ppmv	86	926.9	1398000	1508
Griffith	CTG/HRSG	SCR	4	ppmv	84	906.1	1339000	1478
Griffith	CTG/HRSG	SCR	4.5	ppmv	82	885.2	1282000	1448
Griffith	CTG/HRSG	SCR	9	ppmv	65	697.3	1017000	1459
Calpine (unofficial; not in RBLC)	CTG/HRSG	SCR	3	ppmv		1663	1756000	1062
Brooklyn Navy Yard Cogen	Natural Gas Turbine	SCR	3.5	ppmv				
Blue Mountain Power	CTG/HRSG	SCR, Dry Low NOx Burner	4	ppmv	84			
Sithe/Independence Power Partners	Natural Gas Turbines	SCR, Dry Low NOx Burner	4.5	ppmv				
Portland Gen Electric	Natural Gas Turbines	SCR	4.5	ppmv	82			8537
Hermiston Generating	Natural Gas Turbines	SCR	4.5	ppmv	82			
Southern California Gas	Natural Gas Turbine	SCR	8	ppmv	93			
Newark Bay Cogen	Natural Gas Turbines	SCR	8.3	ppmv				
UNOCAL	Natural Gas Turbine	SCR, Water Injection	9	ppmv	80			
Mid-Georgia Cogen	Natural Gas Turbines	SCR, Dry Low NOx Burner	9	ppmv				
Formosa Plastics	CTG/HRSG	Dry Low NOx Burner, Combustion Design & Control	9	ppmv				181
Milagro, Williams Field Service	Natural Gas Turbines	Dry Low NOx Burner	9	ppmv	94			
Saranac Energy	Natural Gas Turbines	SCR	9	ppmv				
Selkirk Cogen	Natural Gas Turbines	SCR, Steam Injection	9	ppmv				
PASNY/Holtsville Combined Cycle	Natural Gas Turbine	Dry Low NOx Burner	9	ppmv				
Narragansett Electric/NE Power	Natural Gas Turbine	SCR	9	ppmv				

to the installation of a CO catalyst actually increases the emissions rate of other criteria pollutants, such as NO_x, on a per unit of power output basis.

Throughout the life of the plant, catalyst elements will require periodic replacement. Currently, oxidation catalyst manufacturers are willing to guarantee a catalyst life of three years. The use of the oxidation catalyst system increases the energy requirements of the facility. Maintenance costs consist of routine catalyst replacement costs. Labor for operation and maintenance of the combustion control system is assumed to be negligible. The labor costs for the oxidation catalyst include general maintenance of the system. This oxidation catalyst system adds $630,000 to a unit's annual costs.

Though not included in the economic analysis, an oxidation catalyst may increase corrosion on the HRSG and stack. This would occur because an oxidation catalyst, as designed for this facility, would oxidize 3 to 6 percent of the SO_2 to SO_3. The ammonia present in the flue gas from any included SCR system will react with the SO_3 to form ammonium sulfate and bisulfate salts. Even though the minimal amount of sulfur in the natural gas used for this project would mitigate any potential concern for significant emissions of the compounds, these compounds would cause rapid corrosion on the back end of the HRSG and on the stack. These corrosion problems would require plant shut down for cleaning and repairs.

A comparison of the control systems considered by the applicant are presented and compared with previously permitted CO control systems taken from the RBLC in Table 4. A review of the RBLC data in Table 4 indicates that combined cycle projects have recently been permitted both with and without oxidation catalyst. The use of a CO catalyst represents LAER and it has typically been applied only to those simple cycle or combined cycle units that are located in CO non-attainment areas, in or near large urban areas, or are being used on units that have significant design and/or economic differences compared to Griffith.

BACT for CO is represented by the Calpine Southpoint Project, a 520 MW combined cycle project with F Class combustion turbine generators similar to those proposed for the Griffith Energy Project. Calpine, which is proposed to be built in the same geographical area as Griffith Energy, has recently been issued a draft PSD permit by EPA Region IX. The CO emission rate proposed by the applicant would be lower than that in the Calpine draft permit. The Calpine draft permit does not require a CO catalyst as an emission control.

Table 4: CTG/HRSG BACT Comparison for CO

Facility	Process	Control Technology	Emiss. Limit	Emiss. Limit Unit	Cntrl Eff	Tons Controlled	Cost ($)	$/ton Controlled
Griffith	CTG/HRSG	SCONOx w/Duct Burner	2	ppmv	88	383.8	5393000	14052
Griffith	CTG/HRSG	SCR/Oxidation Catalyst w/Duct Burner	3	ppmv	82	355.7	630000	1771
Griffith	CTG/HRSG	Combustion Controls w/Duct Burner	20	ppmv				
Griffith	CTG	Combustion Controls w/out Duct Burner	20	ppmv				
Calpine (unofficial; not in RBLC)	CTG	Combustion Controls w/out Duct Burner	10	ppmv				
Calpine (unofficial; not in RBLC)	CTG/HRSG	Combustion Controls w/Duct Burner	35	ppmv				
Newark Bay Cogen	Natural Gas Turbines	Oxidation Catalyst	1.8	ppmv				
Saranac Energy	Natural Gas Turbines	Oxidation Catalyst	3	ppmv				
Blue Mountain Power	CTG/HRSG	Oxidation Catalyst	3.1	ppmv	80			
Brooklyn Navy Yard Cogen	Natural Gas Turbine	Combustion Controls	4	ppmv				
PASNY/Holtsville Combined Cycle	Natural Gas Turbine	Combustion Controls	8.5	ppmv				
Selkirk Cogen	Natural Gas Turbines	Combustion Controls	10	ppmv				
Unocal	Natural Gas Turbine	Oxidation Catalyst	10	ppmv	75			
Orlando Utilities Commission	Natural Gas Turbines	Combustion Controls	10	ppmv				
Mid-Georgia Cogen	Natural Gas Turbines	Complete Combustion	10	ppmv				
Narragansett Electric/NE Power	Natural Gas Turbine		11	ppmv				
Sithe/Independence Power Partners	Natural Gas Turbines	Combustion Controls	13	ppmv				
Portland General Electric	Natural Gas Turbines	Good Combustion Practices	15	ppmv				
Hermiston Generating	Natural Gas Turbines	Good Combustion Practices	15	ppmv				
Auburndale Power Partners	Natural Gas Turbine	Good Combustion Practices	15	ppmv				

On the basis of these many significant energy, environmental, and economic negative impacts, the installation of an oxidation catalyst is ruled out as BACT for CO emissions. The use of combustion controls has been previously recognized as BACT by regulatory agencies for the control of CO. Thus, the applicant proposed combustion practice be considered as BACT due to the high cost of CO removal and the negative impacts on overall emissions.

The applicant proposed that BACT be the use of modern combustion control technology to limit CO emissions from the CTG, with or without duct firing, to 20 ppmvd at 15 percent O_2, or 98.5 lb/hr with duct firing and 59.0 lb/hr without duct firing. Upon review of the data, ADEQ concurs with and approves the applicant's proposal.

3) Volatile Organic Compounds

The applicant's BACT analysis for VOCs examined catalytic oxidation and combustion controls. Catalytic oxidation is principally used to control CO emissions, but can be used to reduce some VOC emissions. However, the negative energy, economic, and environmental impacts enumerated in the previous section are still applicable. Any VOC emission control from catalytic oxidation would be realized at a very high cost per ton removed due to the high capital cost of the system and the generally ineffective removal of VOC emissions by CO catalysts.

The applicant proposed, and ADEQ concurs that BACT is considered to be the use of combustion controls to achieve 35.2 lb/hr, or 6.1 nanograms per joule heat input (0.014 lb per million Btu) with duct firing. Without duct firing, the proposed emission limit is 7.4 lb/hr, or 1.7 nanograms per joule heat input (0.0040 lb per million Btu). These emission limits compare favorably to the VOC emission limit on the recently permitted Calpine facility, which is 83.1 lb/hr with or without duct firing.

4) Particulate Matter (PM)

The emission of particulate matter from the project will be controlled by ensuring as complete combustion of the natural gas as possible and by minimizing SO_2 and SO_3 oxidation. Natural gas contains only trace quantities of non-combustible material, and the manufacturers's standard operating procedures include filtering the turbine inlet air and combustion controls.

The applicant proposed that BACT for PM is the use of combustion controls. The maximum allowable PM emission rates proposed are 28.2 lb/hr with duct firing and 17.8 lb/hr without duct firing. A comparison of the control systems considered by the applicant are presented and compared with previously permitted control systems taken from the RBLC in Table 5. As shown in Table

5, the proposed limit without duct burning is lower than the Calpine permitted limit, and somewhat higher with duct burning only due to heavier application of duct burning at the Griffith facility. The RBLC documents do not list any post-combustion particulate matter control technologies being used on combustion turbines. Consistent with the previous determinations, the use of combustion controls is the proposed BACT for particulate matter.

The applicant proposed an emission limit for the CTG/HRSG of 28.2 lb/hr, or 5.2 nanograms per joule heat input (0.012 lb per million Btu), with duct firing, and 17.8 lb/hr, or 4.2 nanograms per joule heat input (0.0097 lb per million Btu) without duct firing. In addition, the applicant agreed to an opacity limit of 10 percent for visible emissions. ADEQ agrees that these combustion control emissions represent BACT for PM emissions for the specific CTG/HRSG design considered in this analysis. This design includes the optimum operational efficiency as well as the use of SCR for limiting NO_x.

5) Sulfur Dioxide

Since the natural gas fuel is inherently low in sulfur content, additional emission controls have not been required or developed that would reduce emissions further. ADEQ concurs with the applicant's proposal that BACT for SO_2 is considered to be the use of natural gas fuel, with sulfur content limited to a maximum of 0.75 gr/100 dscf. The emission limit is proposed as 5.7 lb/hr, or 0.99 nanograms per joule heat input (0.0023 lb per million Btu) with duct firing, and 4.2 lb/hr, or 0.99 nanograms per joule heat input (0.0023 lb per million Btu) without duct firing.

B) Auxiliary Boiler

The auxiliary boiler will be an industrial package boiler that has a maximum fuel burn rate of 38 MMBtu/hr. Natural gas is the only fuel to be used. To limit emissions of sulfur oxides (SO_2 and SO_3), the maximum allowable sulfur content in the natural gas will be 0.75 grains/100 dscf.

1) Nitrogen Oxides

The applicant considered a number of measures for the control of NO_x emissions from the proposed project, including both in-combustor NO_x formation control, and post-combustion emission reduction. In-combustor CTG NO_x controls considered included lowering combustion temperatures, flue gas recirculation, and minimizing excess combustion air. Selective Catalytic Reduction (SCR), and Selective Non-Catalytic Reduction (SNCR) were considered as post-combustion NO_x control systems.

Table 5: CTG/HRSG BACT Comparison for PM

Facility	Process	Control Technology	Emiss. Limit	Emiss. Limit Unit	Cntrl Eff.	$/ton Controlled
Griffith	CTG/HRSG	Combustion Controls w/Duct Burner	0.012	lb/MMBtu		
Griffith	CTG	Combustion Controls w/out Duct Burner	0.0097	lb/MMBtu		
Calpine (unofficial; not in RBLC)	CTG/HRSG	Combustion Controls w/Duct Burner	22.8	lb/hr		
Calpine (unofficial; not in RBLC)	CTG	Combustion Controls w/out Duct Burner	18.3	lb/hr		
Narragansett Electric/NE Power	CTG/HRSG		0.005	lb/MMBtu		
Newark Bay Cogen	Natural Gas Turbines	Turbine Design	0.006	lb/MMBtu		
Saranac Energy Company	Natural Gas Turbines	Combustion Controls	0.0062	lb/MMBtu		
Hartwell Energy	Natural Gas Turbines	Clean Burning Fuels	0.0064	lb/MMBtu		
Kamine/Besicorp Syracuse	Natural Gas Turbine	Sulfur Content Not to Exceed 0.15% by Weight	0.008	lb/MMBtu		
Tempo Plastics	Natural Gas Turbine	Lube Oil Vent Coalescer	0.012	lb/MMBtu		
Auburndale Power Partners	Natural Gas Turbine	Good Combustion Practices	0.0136	lb/MMBtu		
TBG Cogen	Natural Gas Turbine	Sulfur Content Not to Exceed 0.037% by Weight	0.024	lb/MMBtu		
Megan-Racine Associates	Natural Gas Turbine	No Controls	0.028	lb/MMBtu		
CNG Transmission	Natural Gas Turbine	Use of Natural Gas	0.035	lb/MMBtu		
Casco Ray Energy	Natural Gas Turbines		0.06	lb/MMBtu		

Lowering combustion temperatures was rejected as a control strategy because of the increased CO and VOC which result from incomplete combustion of the fuel. SCR is not feasible since the gas temperatures at the point where the control would be applied is well below the minimum SCR manufacturer recommended operating temperatures. SNCR was rejected because of considerations such as package boiler temperature profile, residence time, and geometry of the boiler, as well as the increased energy requirements for operation. A comparison of the control system proposed by the applicant is compared with previously permitted control systems taken from the RACT/BACT/LAER clearinghouse in Table 6. The applicant proposed, and ADEQ concurs that BACT for NOx is considered to be flue gas recirculation and the use of low-NO_x burners to meet an emission limit of 3.5 lb/hr, or 40 nanograms per joule heat input (0.092 lb per million Btu).

2) Carbon Monoxide

The applicant considered oxidation catalysts, higher combustion temperatures, and good combustion controls as potential CO emission controls. An oxidation catalyst system was ruled out because the range of temperatures available in the auxiliary boiler is less than optimum for the catalyst. Higher boiler combustion temperature was rejected as a control strategy since it would result in increased NO_x emissions. A comparison of the control system proposed by the applicant is compared with previously permitted control systems taken from the RACT/BACT/LAER clearinghouse in Table 7. ADEQ concurs that BACT is considered to be the use of good combustion controls to limit emissions to 2.1 lb/hr, or 24 nanograms per joule heat input (0.055 lb per million Btu).

3) Volatile Organic Compounds

The applicant considered oxidation catalysts, higher combustion temperatures, and good combustion controls as potential VOC emission controls. An oxidation catalyst system was ruled out because the range of temperatures available in the auxiliary boiler is less than optimum for the catalyst. Higher boiler combustion temperature was rejected as a control strategy since it would result in increased NO_x emissions. ADEQ concurs that BACT is considered to be the use of good combustion controls and low-NO_x burners to limit emissions to 0.49 lb/hr, or 5.6 nanograms per joule heat input (0.013 lb per million Btu), for VOC.

4) Particulate Matter (PM)

The emission of particulate matter from the project will be controlled by ensuring as complete combustion of the natural gas as possible and by

Table 6: Auxiliary Boiler BACT Comparison for NO_x

Facility	Process	Control Technology	Emiss. Limit	Emiss. Limit Unit	Cntrl Eff	Tons Controlled	Cost ($)	$/ton Controlled
Griffith	Natural Gas Aux. Boiler	Flue Gas Recirculation and Low-Nox Burners	0.092	lb/MMBtu				
Kalamazoo Power Limited	Natural Gas Backup Boiler		0.02	lb/MMBtu				
Kamine/Beiscorp Syracuse	Utility Boiler	Flue Gas Recirculation	0.035	lb/MMBtu	70.9			
Sunland Refinery	Boilers	Flue Gas Recirculation and Low-Nox Burners	0.036	lb/MMBtu				
Newark Bay Cogen	Natural Gas Aux. Boiler	Flue Gas Recirculation and Low-Nox Burners	0.05	lb/MMBtu	75			
Newark Bay Cogen	Natural Gas Aux. Boiler	Flue Gas Recirculation and Low-Nox Burners	0.05	lb/MMBtu				
Champion International	Natural Gas Boiler	Flue Gas Recirculation	0.05	lb/MMBtu				
I/N Kote	Package Boiler	Flue Gas Recirculation and Use of Natural Gas	0.05	lb/MMBtu				
Grain Processing	Boilers	Flue Gas Recirculation and Low-Nox Burners	0.05	lb/MMBtu				
Anitec Cogen	Auxiliary Boiler	No Controls	0.05	lb/MMBtu				
James River	Boiler	Flue Gas Recirculation and Low-Nox Burners	0.06	lb/MMBtu	70			
Indelk Energy Services Ostego	Natural Gas Boiler	Flue Gas Recirculation	0.06	lb/MMBtu	40			
American Crystal Sugar	Natural Gas Boiler	Flue Gas Recirculation and Low-Nox Burners	0.075	lb/MMBtu				
Milagro Williams Field Service	Boiler	Flue Gas Recirculation and Low-Nox Burners	0.08	lb/MMBtu	77			
IMC-Agrico Faustina	Utility Boiler	Low-Nox Burners	0.08	lb/MMBtu				170

minimizing SO_2 and SO_3 oxidation. Natural gas contains only trace quantities of non-combustible material, and the manufacturers's standard operating procedures include filtering the turbine inlet air and combustion controls. ADEQ concurs that BACT is considered to be the use of combustion controls to limit emissions to 0.19 lb/hr, or 2.2 nanograms per joule heat input (0.0050 lb per million Btu), for PM.

5) Sulfur Dioxide

Since the natural gas fuel is inherently low in sulfur content, additional emission controls have not been required or developed that would reduce emissions further. ADEQ concurs that BACT is considered to be the use of natural gas fuel containing no more than 0.75 gr/100 dscf as BACT for SO_2. The proposed emission limit is 0.09 lb/hr, or 1.0 nanograms per joule heat input (0.0024 lb per million Btu).

C) Cooling Towers

Two cooling towers are being provided with this project: the steam turbine condensate (main) cooling tower and the chiller water cooling tower. Typically, drift eliminators are used to minimize drift (droplet) losses. ADEQ agrees that the high efficiency drift eliminators which control emissions to 5.9 lb/hr, or 0.83 lb/million gallon of circulating water flow, for the main cooling tower, and 1.4 lb/hr, or 0.88 lb/million gallon of circulating water flow, for the chiller cooling tower, are BACT for PM for the cooling towers.

V. IMPACTS TO AMBIENT AIR QUALITY

An air quality impacts analysis was conducted using EPA's air quality dispersion model Industrial Source Complex Short Term (ISCST). Maximum emission rates as presented in Table 8 were modeled as steady state emissions for continuous operation, 8,760 hours per year. The results of the analysis indicate that no National Ambient Air Quality Standards (NAAQS) or State of Arizona standards would be violated by the Griffith Energy facility (State of Arizona standards are identical to NAAQS).

Predicted maximum offsite concentrations in the Class II area surrounding the plant are presented in Table 9a and 9b. Predicted maximum offsite concentrations at Grand Canyon National Park, a Class I area, are presented in Table 10. The Grand Canyon is the only Class I area in the modeling region. Concentrations are compared to both the NAAQS and the maximum allowable incremental increase in air pollutant concentrations occurring over the baseline concentration (A.A.C. R18-2-218.A.) in classified attainment areas I and II.

Table 7: Auxiliary Boiler BACT Comparison for CO

Facility	Process	Control Technology	Emiss. Limit	Emiss. Limit Unit	Cntrl Eff	Tons Controlled	Cost ($)	$/ton Controlled
Griffith	Natural Gas Aux. Boiler	Good Combustion Practices	0.055	lb/MMBtu				
Kalamazoo Power Limited	Natural Gas Backup Boiler		0.003	lb/MMBtu				
Kamine/Beiscorp Syracuse	Utility Boiler	No Controls	0.038	lb/MMBtu				
Indeck-Yerkes Energy Services	Natural Gas Aux. Boiler	No Controls	0.038	lb/MMBtu				
Newark Bay Cogen	Natural Gas Aux. Boiler	Boiler Design	0.04	lb/MMBtu				
Grain Processing	Boilers	Good Combustion Practices	0.04	lb/MMBtu				
Indeck Energy	Natural Gas Aux. Boiler	No Controls	0.042	lb/MMBtu				
Lakewood Cogen	Natural Gas Boiler	Boiler Design	0.042	lb/MMBtu				
Mid-Georgia Cogen	Natural Gas Boiler	Complete Combustion	0.05	lb/MMBtu				

Table 8: Maximum Allowable Emission Rates

Unit	Pollutant	Pounds per Hour	Tons per Year	lb/MMBtu (or other units, as specified)
001-Combustion Turbine Generator/HRSG with Duct Firing -- West Stack	PM	28.2	123.52	0.012
	SO_x	5.7	24.91	0.0023
	NO_x	28.6	125.27	3.0 ppmvd at 15% O_2
	VOCs	35.2	154.07	0.015
	CO	98.5	431.25	20 ppmvd at 15% O_2
	Formaldehyde	5.0	21.86	0.0020
002- Combustion Turbine Generator/HRSG with Duct Firing -- East Stack	PM	28.2	123.52	0.012
	SO_x	5.7	24.91	0.0023
	NO_x	28.6	125.27	3.0 ppmvd at 15% O_2
	VOCs	35.2	123.52	0.015
	CO	98.5	431.25	20 ppmvd at 15% O_2
	Formaldehyde	5.0	21.86	0.0020
001-Combustion Turbine Generator/HRSG without Duct Firing -- West Stack	PM	17.8	78.0	0.011
	SO_x	4.2	18.4	0.0023
	NO_x	21.1	92.4	3.0 ppmvd at 15% O_2
	VOCs	7.4	32.4	0.0040
	CO	59.0	258.4	20 ppmvd at 15% O_2
	Formaldehyde	4.9	3.59	0.0027
002- Combustion Turbine Generator/HRSG without Duct Firing -- East Stack	PM	17.8	78.0	0.011
	SO_x	4.2	18.4	0.0023
	NO_x	21.1	92.4	3.0 ppmvd at 15% O_2
	VOCs	7.4	32.4	0.0041
	CO	59.0	258.4	20 ppmvd at 15% O_2
	Formaldehyde	4.9	3.59	0.0027
003-Auxiliary Boiler	PM	0.19	0.83	0.0050
	SO_x	0.09	0.38	0.0024
	NO_x	3.5	15.24	0.092
	VOCs	0.49	2.15	0.013
	CO	2.1	9.11	0.055
Main Cooling Tower (8 Cells)	PM	5.9	25.93	0.83 lb/million gallon
Chiller Cooling Tower (6 Cells)	PM	1.4	6.31	0.88 lb/million gallon

Note: PM = Total Suspended Particulate for these sources.

Table 9a. National Ambient Air Quality Standards (NAAQS) Analysis

Pollutant	Period	Predicted Maximum Concentrations: Griffith Energy Project (μg/m^3)	Predicted Maximum Concentrations: Griffith Energy Plus Other Nearby Sources[1] (μg/m^3)	Background Values[2] (μg/m^3)	Sum of Griffith, Nearby Sources[1] and Background[2] (μg/m^3)	NAAQS (μg/m^3)
PM_{10}	Annual	1.66	1.66	12	13.66	50 (mean)
	24 hr	19.22	19.22	44.8	64.02	150 (mean)
SO_2	Annual	0.41	0.41	Modeled	0.41	80 (mean)
	24 hr	3.92	4.14	Modeled	4.14	365 (max)
	3 hr	7.99	20.14	Modeled	20.14	1300 (max)
CO	8 hr	100.4	136.97	Modeled	636.97	10000 (max)
	1 hr	561.61	1828.33	Modeled	1823.33	40000 (max)
NO_2	Annual	10.42	10.85	Modeled	10.85	100 (max)

Table 9b. PSD Class II Increment Analysis

Pollutant	Period	Predicted Maximum Concentrations: Griffith Energy Project (μg/m^3)	Predicted Maximum Concentrations: Griffith Energy Plus Other Nearby Sources[1] (μg/m^3)	Allowable Class II Increment (μg/m^3)
PM_{10}	Annual	1.66	1.66	17 (mean)
	24 hr	19.22	19.22	30 (max)
SO_2	Annual	0.41	0.41	20 (mean)
	24 hr	3.92	4.14	91 (max)
	3 hr	7.99	20.14	512 (max)
CO	8 hr	100.4	136.97	NA
	1 hr	561.61	1828.33	NA
NO_2	Annual	10.42	10.85	25 (mean)

1 Other nearby sources are: North Star Steel, Mojave Pipeline Operating Company - Topock Compressor Station, Ford Proving Grounds, El Paso Natural Gas Company at Dutch Flats, South Point Power Plant, and Guardian Fiberglass Inc.

2 PM_{10} background data was obtained from Praxair Inc., located approximately two miles south of the Griffith facility. The highest annual average of 12.00 μg/m^3, from 1993-1996 monitored data, was used as the background value. The highest 24-hour values from 1993-1996 monitored data were evaluated. Of these four years, the second highest-high of 44.80 μg/m^3 from 1993 was used as the background value. In lieu of monitored background, values for SO_2, CO and NO_2 were obtained by modeling all nearby sources.

Table 10. Predicted Maximum Ambient Air Concentrations at Grand Canyon NP Compared to Allowable Standards

Pollutant	Period	Source Modeled Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent of NAAQS (%)	Class I Increment ($\mu g/m^3$)	Percent of Class I Increment (%)
PM_{10}	Annual	0.008	50 (mean)	0.02	4	0.2
	24 hr	0.246	150 (mean)	0.16	8	3.07
SO_2	Annual	0.0009	80 (mean)	0.001	2	0.05
	24 hr	0.028	365 (max)	0.007	5	0.5
	3 hr	0.2093	1300 (max)	0.02	25	0.8
CO	8 hr	1.359	10000 (max)	0.01	NA	NA
	1 hr	10.88	40000 (max)	0.03	NA	NA
NO_2	Annual	0.007	100 (max)	0.007	2.5	0.3

NA = Not applicable

VI. APPLICABLE REGULATIONS VERIFICATION

The Permittee has identified the applicable regulations that apply to each unit in its permit application. Table 11 summarizes the findings of the Department with respect to those regulations that are applicable to each unit and describes the control equipment used for each emission unit. The use of natural gas and good combustion techniques is assumed.

Table 11. Applicable Regulations Verification

Unit ID	Control Equipment	Applicable Regulations	Verification
001 and 002- Combustion Turbine Generators/HRSGs from west and east stacks, respectively	Low NOx burners and SCR	40 CFR 60, Subpart GG 40 CFR 72 40 CFR 73 40 CFR 75 40 CFR 60 Subpart Da	Gas Turbine ≥10 MMBtu/hr and burning natural gas. Electric Utility Steam Generating Units >250 MMBtu/hr and burning natural gas.
003 - Auxiliary Boiler	Natural gas Low NOx burner FGR	40 CFR 60 Subpart Dc	Small Industrial-Commercial- Institutional Steam Generating Unit ≥10 and <100 MMBtu/hr, natural gas fuel

VII. ADDITIONAL IMPACT ANALYSIS

A) Growth Analysis

The applicant proposed that a detailed analysis of the project’s effect on growth is not necessary, due to the fact that growth impacts resulting from operations at the project are expected to be insignificant. About 25 permanent workers would be employed at the project, and no significant increase in industrial, commercial, or residential growth to accommodate these workers is expected. Any increase in the number of motor vehicle trips or miles traveled resulting from the project’s workforce is also expected to be insignificant relative to the existing highway traffic in the area.

B) Soils and Vegetation Analysis

The applicant performed an analysis of acid deposition, as daily averages of HNO_3 and SO_2 deposited in kilograms per hectare, at Class I and Class II areas using methods outlined in the Interagency Workgroup on Air Quality Modeling Phase 1 Report, June,

1993. The results were as follows:
Grand Canyon – 0.059 kg HNO_3/hectare, 0.001 kg SO_2/hectare;
Lake Mead National Recreation Area – 0.13 kg HNO_3/hectare, 0.001 kg SO_2/hectare;
Wabayuma Wilderness – 3.327 kg HNO_3/hectare, 0.031 kg SO_2/hectare;
Warm Springs Wilderness – 0.097 kg HNO_3/hectare, 0.001 kg SO_2/hectare; and
Mt. Nutt Wilderness – 0.601 kg HNO_3/hectare, 0.006 kg SO_2/hectare.

C) Visibility Impairment Analysis

The applicant performed an initial visibility impairment analyses at Class I areas using output from both ISCST3 and CALPUFF models and methods outlined in the Interagency Workgroup on Air Quality Modeling Phase 1 Report, June, 1993. Analyses for Class II areas was performed using EPA approved methods utilizing a Level I screening procedure and the VISCREEN model.

The initial screening analysis at the Grand Canyon, the only Class I area in the vicinity of the project, indicated the possibility of significant impacts. As a result, a CALPUFF refined modeling assessment was performed. The screening mode of the CALPUFF modeling system predicted a maximum change in extinction coefficient at the Grand Canyon of 3.03 percent, which is below the five percent limit of acceptable change. This result should be considered conservative, because it assumes combustion turbine NO_x emissions were 4.5 ppmv, whereas the proposed combustion turbine emissions are 3.0 ppmv. The modeling results at the Grand Canyon suggest that the project will also not adversely affect resources at the Lake Mead National Recreation Area, a Class II area 40 kilometers to the west of the project.

The three Class II areas which are very close to the project site are: Wabayuma Wilderness – eight kilometers, Warm Springs Wilderness – seven kilometers, and Mt. Nutt Wilderness – 13 kilometers. Based on the analysis, it was estimated that the visibility may be impaired as follows: Wabayuma Wilderness 10.9 percent of the year, Warm Springs Wilderness 8.9 percent of the year, and the Mt. Nutt Wilderness 11.3 percent of the year.

D) Formaldehyde Impact Analysis

Maximum impacts at or beyond the facility's process area boundary were estimated for one hour, 24 hours, and for the period of the meteorological data (18 months). Modeling results and comparison to the appropriate AAAQG are shown in Table 12. Based on these results, there should be no adverse impacts to human health from the emission of formaldehyde.

Table 12: Formaldehyde Maximum Modeled Concentrations

Averaging Period	Modeled Formaldehyde Concentration ($\mu g/m^3$)	Formaldehyde AAAQG ($\mu g/m^3$)
Annual	0.022	0.08
24-Hour	0.37	12.0
1-Hour	1.87	20.0

VIII. PERIODIC MONITORING

A. CTG/HRSG Units 1 and 2 With Duct Firing

The CTG/HRSG Units 1 and 2 may be operated in combined cycle operation and may only burn pipeline quality natural gas. Under combined cycle operation, exhaust from Gas Turbine 1 is used to provide intake air to the Steam Unit 1 windbox. This is done to increase the load output and efficiency of the system. Table 8 presents the allowable emissions for these units.

Opacity: The CTG/HRSG units are subject to the opacity standard of 10% under the BACT rule in A.A.C. R18-2-406.A.4. Natural gas is a clean burning fuel and operation of these type of units generally indicate that opacity problems are rare. Hence, no ongoing periodic monitoring is required when burning natural gas.

PM: The units are subject to a particulate matter emissions limitation resulting from the use of BACT. Natural gas is a clean burning fuel and results in negligible particulate matter emissions when operated properly. Therefore, it was determined that a verification through an initial performance test would fulfill the requirements for periodic monitoring when burning natural gas.

SO_2: The units are subject to a limit of 0.75 grains of sulfur/100dscf in the natural gas. This limit will be demonstrated by the permittee maintaining a vendor-provided copy of that part of the Federal Energy Regulatory Commission (FERC)-approved tariff agreement that contains the sulfur content and the lower heating value of the pipeline quality natural gas.

NOx: The units are subject to a NOx emissions limitation resulting from the use of BACT. The source is required to operate, maintain, and calibrate a compliance CEMS for NOx.

CO: The units are subject to a CO emissions limitation resulting from the use of BACT. The source is required to operate, maintain, and calibrate a compliance CEMS for CO.

VOC: The units are subject to a VOC emissions limitation resulting from the use of BACT. Verification through annual performance testing will fulfill the requirements for periodic monitoring.

B. CTG/HRSG Units 1 and 2 Without Duct Firing

The CTG/HRSG Units 1 and 2 may be operated in combined cycle operation and may only burn pipeline quality natural gas. Under combined cycle operation, exhaust from Gas Turbine 1 is used to provide intake air to the Steam Unit 1 windbox. This is done to increase the load output and efficiency of the system. Table 8 presents the allowable emissions for these units.

Opacity: The CTG/HRSG units are subject to the opacity standard of 10 percent under the BACT rule in A.A.C. R18-2-406.A.4. Natural gas is a clean burning fuel and operation of these type of units generally indicate that opacity problems are rare. Hence, no ongoing periodic monitoring is required when burning natural gas.

PM: The units are subject to a particulate matter emissions limitation resulting from the use of BACT. Natural gas is a clean burning fuel and results in negligible particulate matter emissions when operated properly. Therefore, it was determined that a verification through initial performance testing would fulfill the requirements for periodic monitoring when burning natural gas.

SO_2: The units are subject to a limit of 0.75 grains of sulfur/100 dscf in the natural gas. This limit will be demonstrated by the permittee maintaining a vendor-provided copy of that part of the Federal Energy Regulatory Commission (FERC)-approved tariff agreement that contains the sulfur content and the lower heating value of the pipeline quality natural gas.

NOx: The units are subject to a NO_x emissions limitation resulting from the use of BACT. The source is required to operate, maintain, and calibrate a compliance CEMS for NO_x.

CO: The units are subject to a CO emissions limitation resulting from the use of BACT. The source is required to operate, maintain, and calibrate a compliance CEMS for CO.

VOC: The units are subject to a VOC emissions limitation resulting from the use of BACT. Verification through annual performance testing will fulfill the requirements for periodic monitoring.

C. Auxiliary Boiler

For continuous monitoring compliance for the auxiliary boiler, Griffith Energy proposes to monitor and maintain records of daily fuel usage. Compliance will be determined by reviewing these data relative to the fuel usage rates that were submitted with the application.

Specifically these requirements include:

- 40 CFR 60.48c(a)(1) and (3) - Start up reporting, design heat capacity, fuel identification, and annual capacity factor.
- 40 CFR 60.48e(11)(g) and (I) - Recording and record keeping of daily fuel usage.

IX. TESTING REQUIREMENTS

A. CTG/HRSG Units 1 and 2 With Duct Firing

Griffith Energy is required to perform initial performance tests for PM, NOx, CO, and VOC in accordance with 40CFR60.48a(f) and 40CFR60.335(b). Annual performance tests for VOC will demonstrate compliance with VOC emission limits.

B. CTG/HRSG Units 1 and 2 Without Duct Firing

Griffith Energy is required to perform initial performance tests for PM, NOx, CO, and VOC in accordance with 40CFR60.335(b) when there is no supplemental duct firing. Annual performance tests for VOC will demonstrate compliance with VOC emission limits.

C. Auxiliary Boiler

The auxiliary boiler is subject to 40CFR60 Subpart Dc. This regulation contains emission limits and monitoring requirements for particulates and SO_2, however, these only apply to boilers fired on solid or liquid fuels. For boilers that are fired on natural gas, Subpart Dc only requires reporting and record keeping requirements, but no testing. However, the permittee will demonstrate compliance with an initial performance test of PM, NOx, CO and VOC, followed by continuous monitoring of the proposed auxiliary boiler's natural gas usage.

X. INSIGNIFICANT ACTIVITIES

The activities identified in Table 13 have been deemed insignificant.

Table 13: Insignificant Activities

Activity No.	Source Description	Comments
1	Building HVAC Exhaust Vents	Insignificant pursuant to Arizona Rule R18-2-101.54.j.
2	Turbine Compartment Ventilation Exhaust Vents	Insignificant pursuant to Arizona Rule R18-2-101.54.j.
3	Sanitary Sewer Vents	Insignificant pursuant to Arizona Rule R18-2-101.54.j.
4	Compressed Air Systems	Insignificant pursuant to Arizona Rule R18-2-101.54.j.
5	Turbine Lube Oil Vapor Extractors and Lube Oil Mist Eliminator Vents	Insignificant pursuant to Arizona Rule R18-2-101.54.j.
6	Steam Drum Safety Relief Valve Vents	Insignificant pursuant to Arizona Rule R18-2-101.54.j.
7	Building Air Conditioning Units	Insignificant pursuant to Arizona Rule R18-2-101.54.j.
8	Emergency Diesel Fire Pump Exhaust Stack	Insignificant pursuant to Arizona Rule R18-2-101.54.h.
9	Emergency Diesel Fire Pump Fuel Storage Tank	Insignificant pursuant to Arizona Rule R18-2-101.54.j.
10	Sulfuric Acid Storage Tank Vents	Subject to A.A.C. R18-2-730.F.
11	Various Steam Release Vents	Insignificant pursuant to Arizona Rule R18-2-101.54.j.
12	Welding Equipment	Insignificant pursuant to Arizona Rule R18-2-101.54.j.
13	Lab Hood Vents	Insignificant pursuant to Arizona Rule R18-2-101.54.i.
14	Water Wash System Storage Tank Vents	Insignificant pursuant to Arizona Rule R18-2-101.54.j.
15	Neutralization Basin	Insignificant pursuant to Arizona Rule R18-2-101.54.j.
16	Sodium Hypochlorite Storage Tank	Insignificant pursuant to Arizona Rule R18-2-101.54.j.
17	Hydrazine Storage Tank Vent	Insignificant pursuant to Arizona Rule R18-2-101.54.j.
18	Fuel Purge Vents	Insignificant pursuant to Arizona Rule R18-2-101.54.j.
19	Oil/ Water Separator Waste Oil Collection Tank Vents	Insignificant pursuant to Arizona Rule R18-2-101.54.j.
20	Sodium Hydroxide Tank	Subject to A.A.C. R18-2-730.F.
21	Condenser Vacuum Pump Vents	Insignificant pursuant to Arizona Rule R18-2-101.54.j.